# 7 Software Modeling Tools

## 7.1 Description of the TEAM™ Model

The LCI uses information modules contained in the TEAM™ software. These modules allow an LCA to be streamlined, one of TEAM™'s special features that allow several processes to be gathered into a single subsystem that may be reused at a higher level. The user may therefore:

- Build complex systems while keeping the interface simple. All the complex processes may be hidden; the main system is simplified on the interface. The user would be able to access any of the subsystems for more process details.
- Model the various life cycle phases within TEAM™ allowing for easy identification of the contribution of each phase.
- Import data from other databases. For example, update the soybean crushing model, and automatically update the TEAM™ model through an import procedure.
- Easily reuse large blocks of information. For instance, a subsystem made for a specific product can be copied, pasted, and instantly reused in another system, yielding significant savings in terms of data collection and calculation.

Figure 73 shows an example of the graphical interface taken directly from TEAM™. An unlimited number of subsystems can be created to organize the information collected. At the reporting stage, the contribution of any given subsystem can be calculated instantly.

NREL researchers use a copy of the TEAM™ model containing the biodiesel and petroleum diesel life cycles, so they can run simulations, update the model, and refine any assumptions. It has also been used for other renewable energy processes being evaluated at NREL.

## 7.2 Description of the Database Used

LCI data for energy production and ancillary materials used in this model came from DEAM™, Ecobalance's database on materials and processes, and literature searches. The DEAM™ database is continuously updated and is one the most extensive LCI databases of environmental impacts associated with products and processes. The following sections describe the type of data in DEAM™.

### 7.2.1 Electricity

Ecobalance has developed a model of the production of electricity for the various regions of the United States, based on primary data sources and EPA AP-42. Wherever possible, the model details precisely the various technologies involved in producing electricity, and relies on weighted averages. For electricity produced from coal combustion, for example, five major groups of boilers were considered, corresponding to various technologies. The models describing the various fuels, as well as how the specific mix of fuels for each zone is taken into account in the model, are described later.

### 7.2.1.1 *Electricity from Coal*

Electricity from coal includes all coal that is burned in utility plants with a total steam-electric and combined nameplate capacity of 50 or more MW. Types of coal include bituminous, subbituminous, lignite, and anthracite. Coal pre-combustion life cycle steps include coal mining, cleaning and preparation for use at utility plants, and transportation to the utilities.

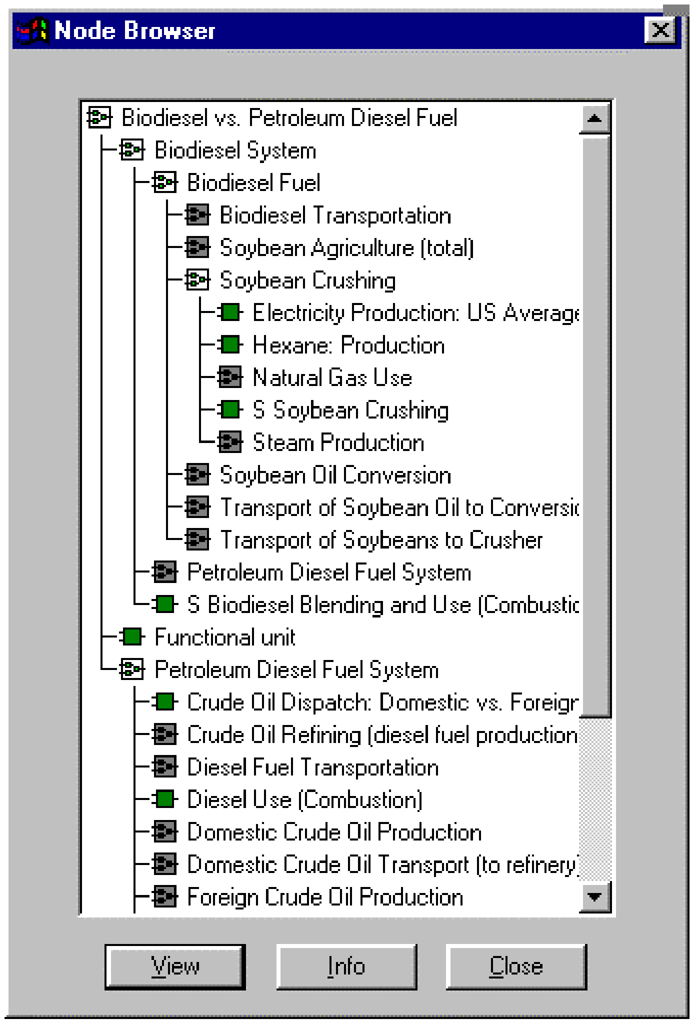


**Figure 82: Example of TEAM™ Interface**

#### 7.2.1.1.1 *Coal Mining*

Materials and energy consumed in mining and cleaning coal comes from 1987 Census Bureau data (DeLucchi, 1993). Emissions from coal mining are from the combustion of diesel oil of mining equipment and methane released directly from the mine. All emissions factors come from AP-42 Mobile Sources vol. II, January 1991. DOE states that water effluents from mining are unquantifiable, and concludes that water effluents from this type of operation generally do not have global impacts[68]; however the local and regional impacts can be significant.

[68] DOE, 1983. Energy Technology Characterizations Handbook section on "Coal Technologies."

### *7.2.1.1.2 Cleaning and Preparation*

Cleaning and preparing coal may involve many processes, including beneficiation, which remove sulfur and mineral matter so that stringent federal emissions limits during combustion are met. However, there are not enough specific data as to the percentage of coal that goes through these processes; and the amount of energy consumed in these processes is negligible compared to the amount of energy generated from coal combustion[69]. Therefore, coal cleaning and preparation steps are omitted from the model.

### *7.2.1.1.3 Transportation from Site of Extraction to Power Plant*

Coal may be transported by various transportation means, including rail, road, pipeline, and barge. The expression used to describe the energy intensity of transporting coal (or any other material) is Btu/ton-mile. This is calculated as:

$$\boxed{\frac{E}{T * M}} \quad \text{(see note 70)}$$

where:

E is total Btu used by the mode of transport and the energy used for the backhaul (assuming the return trip is empty)

T is total tonnage of the transported material

M is the distance the material is carried.

It is safe to assume that the carrier usually returns empty. For example, 91% of the unit train cars that carry coal return empty to the mine (DeLucchi 1993), and trucks return empty unless they can find a similar product to transport back. Therefore, all transportation data will assume a one-way haul and an empty return trip.

### *7.2.1.1.4 Coal–Rail*

The 1987 national average length of haul for coal by rail is 490 miles[71]. We assumed that diesel fuel is used for rail transportation[72]. DeLucchi (1993) presents energy consumed in coal transportation by rail from a few sources (DOE 1983), U.S. Congressional Research Service (CRS) (1977), and Argonne National Laboratory (ANL) (1982). The energy consumed is averaged out to be 589 Btu/ton-mile.

### *7.2.1.1.5 Coal-Truck*

Delucchi (1993) is in accordance with the DOE *Energy Technology Characterizations Handbook* (1983) on an average haul distance of 60 miles for a round trip of coal delivery. It is assumed that diesel fuel is used for truck transportation. DeLucchi estimates energy consumed in coal transportation by truck from a few sources: DOE (1983); CRS (1977); ANL (1982); and Rose (1979). The energy consumed is averaged out to be 2,349 Btu/ton-mile.

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[69] DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix F.

[70] DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix E.

[71].DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*. EIA, 1988. *Coal Distribution.*

[72]DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix F.

#### *7.2.1.1.6 Coal–Ship*

The national average length of haul for coal via water is 450 miles[73]. Delucchi (1993) estimates energy consumed in coal transportation by ship from a few sources DOE (1983); CRS (1977); ANL (1982); and Rose (1979). The energy consumed is averaged 539 Btu/ton-mile.

#### *7.2.1.1.7 Coal Slurry Pipeline*

In general, coal slurry pipeline is a highly reliable (99%) source of transportation, and can last longer than 20 or 30 years. It is the cleanest and safest coal delivery system to power plants. Data for energy consumed in coal transportation by slurry pipeline are presented in *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*[74] (1993) over a few sources: DOE (1983); Banks (1977); and ANL (1982). The energy consumed for this mode of transport averages 668 Btu/ton-mile. Included in this average is energy used for slurry preparation, pipeline pumping, dewatering facilities, and specifically, energy used in the Black Mesa Pipeline, which runs 273 miles from the Black Mesa Coal Mine in Arizona to the Mohave Power Plant in Laughlin, Nevada. DeLucchi estimates that the average length of haul for a pipeline is 300 miles, including the pipeline, tramway transportation, and conveyor belts.

#### *7.2.1.1.8 Water Effluents*

Water effluents coming from precombustion processes are considered negligible for this study. In general, the only water effluents coming from precombustion are those from mining the fuels used to transport materials and refinery processes.

### *7.2.1.2 Coal Combustion*

Energy consumed and emissions associated with coal combustion in utility boilers come from a variety of sources. Emissions and total coal burned were obtained from the 1994 Interim Inventory based on the Form EIA-767 data[75]. Emissions factors for pollutants not provided in the Interim Inventory are obtained from AP-42 (1995).

Emissions are presented for each individual firing configuration. Because firing configurations have varying combustion requirements (coal burning temperatures, firing methods, emissions control equipment, etc.), they emit varying amounts of pollutants.

The firing configurations included in the model are:

- Pulverized coal fired, dry bottom and wall fired
- Pulverized coal fired, dry bottom and tangentially fired
- Pulverized coal-fired and wet bottom
- Spreader stoker
- Fluidized bed combustor
- Cyclone furnace.

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[73] DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*. U.S. Department of Army 1988, 1989. *Waterborne Commerce of the United States,*

[74] DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity.*

[75] Database provided by EPA.

The Interim Inventory provides actual air emissions (VOCs, $NO_x$, CO, $SO_x$, and PM10) by specific type of coal (bituminous, subbituminous, and lignite) and by furnace type. The firing types provided are also identified by a Source Classification Code (SCC). Each firing type is placed into a broader category of firing configurations (identified in AP-42), using SCC numbers. Table 117 presents the firing types provided by the Interim Inventory, and how they were placed in the firing configuration category, based on SCC numbers.

Several steps were taken to obtain actual emissions in pounds per ton of each type of coal. The tonnage for each emission provided by the Interim Inventory database is summed for each firing configuration. This number is divided by the total amount of coal consumed for each firing configuration, to obtain actual emissions per firing configuration, per type of coal.

**Table 117: Coal Fire Configurations Provided by the Interim Inventory (1994)**

| Firing Configuration (AP-42 1995) | Firing Types (Interim Inventory 1994) |
|---|---|
| Pulverized coal fired, dry bottom, wall fired | Front Furnace<br>Arch Furnace (50%)[76]<br>Rear Furnace<br>Spreader Stoker (80%)[77]<br>Opposed Furnace<br>Vertical Furnace |
| Pulverized coal fired, dry bottom and tangentially fired | Tangential Furnace |
| Pulverized coal-fired, wet bottom | Arch Furnace (50%) |
| Spreader stoker | Spreader Stoker (20%) |
| Fluidized bed combustor | Fluidized Bed |
| Cyclone furnace | Cyclone |

Where actual emissions data were not available, such as for $N_2O$, $CH_4$, and trace elements, emissions factors were obtained from AP-42 (1995). A weighted average is used for each firing configuration.

The model also takes into account all $CO_2$ emissions, which are calculated by multiplying 36.7 by the percent weight of carbon content in coal. Fixed carbon content percentages of various coal samples are given in provided Babcock and Wilcox[78] for anthracite, bituminous coal, subbituminous coal, and lignite. Averaged values and $CO_2$ emissions factors (in g/kg coal) are provided in Table 118.

Finally, the model takes the weighted average of each of the firing configurations for each type of coal. For example, the emissions from the spreader stoker for bituminous coal combustion are omitted from the

[76] About half of the arch furnace boilers had SCC numbers for dry-bottom wall-fired units and the other half for wet-bottom units.

[77] An estimated 80% of the spreader stoker boilers had SCC numbers for dry-bottom wall-fired units and the other 20% belonged in the spreader stoker category of firing configurations.

[78] Babcock and Wilcox 1992. *Steam*, 40th ed. Babcock and Wilcox Company, Barberton, OH.

model because bituminous coal combusted in the spreader stoker is a negligible representation of all of the bituminous coal fed into the firing configurations.

#### *7.2.1.2.1 Emissions Control Technology*

Because there are actual plant data for VOCs, $NO_x$, CO, $SO_2$, and PM, emission control technologies for some of the major pollutants of concern, such as $NO_x$ and $SO_x$, are already taken into account.

Lime and limestone, used for flue gas desulfurization (FGD), are modeled. Coal utility plants use different methods for scrubbing, such as limestone slurries and dry spraying, and use as the primary FGD materials lime and limestone. Quantities of lime and limestone vary, depending on the type of coal, the molar ratio needed to scrub the $SO_x$, and the percentage of $SO_x$ (by weight) in the coal. Each type of coal is modeled according to the general scrubbing material for that type of coal and based on its percentage by weight of $SO_x$. Data on scrubbing, molar ratios, and technologies were collected from a source at a coal utility plant in North America (1996), a source at American Electric Power Company (1997) and from the EIA *Electric Power Annual* 1994, vol. II, November 1995.

**Table 118: Coal Carbon and $CO_2$ Emissions Factors**

| | Fixed Carbon Content % | CO2 Emissions Factor (g/kg) |
|---|---|---|
| Anthracite | (see footnote 79) | 2,840 |
| Bituminous | 85 | 3,120 |
| Subbituminous | 75 | 2,753 |
| Lignite | 70 | 2,569 |

#### *7.2.1.2.2 Water Effluents*

Coal combustors use water for boiler makeup, treatment of fumes, and slag cooling. However, we assumed that most of the water is recycled in the facility. Therefore, water effluents generated as a result of combustion of coal are negligible in this model.

### *7.2.1.3 Post-Combustion Products of Coal*

The coal combustion process produces waste that must be disposed of off-site, including coal ash, resulting from coal combustion, and sludge, resulting from FGD. In 1984, $69 \times 10^6$ tons and $16 \times 10^6$ tons of coal ash and FGD sludge, respectively, were generated from electrical facilities[80]. Energy and emissions to remove coal ash and FGD sludge are modeled. Because the quantity of FGD sludge is approximately 25% the amount of coal ash, all energy and emissions to remove and dispose of FGD sludge are considered to be about 25% of those found for the disposal of coal ash.

Energy to transport FGD sludge and coal ash from the plant to their respective storage locations is modeled. The moisture content of coal ash (in % weight of ash) at the point it is removed from the silo is

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[79] Carbon content for anthracite is not needed for the calculation because the EPA Air Emissions Factors provided the emission factor directly.

[80] U.S. EPA 1987. *Wastes from the Combustion of Coal by Electric Utility Power Plants* (taken from DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix F).

assumed to be approximately 17% (moisture content may be 8% to 25%)[81]. The average energy consumed to place ash from the silo into the truck, 0.143 kWh/[82]ton, is very minimal, as most of the work is due to gravitational force (ash falling from the shoot).

#### *7.2.1.3.1 Transportation to the Landfill from the Silo*

The distance from the power plant to the coal ash and FGD sludge landfills is assumed to be 1 mile[83]. The trucks used to transport the materials are tandem trucks, filled based on weight of the material. The tandem truck carries an actual payload of about 27.6 short tons, and consumes 0.038 gallons of diesel fuel per short ton[84] of material.

### *7.2.1.4 Electricity from Heavy Fuel Oil*

Heavy fuel oil, or residual oil, is the fuel oil used in power utilities. This type of oil is produced from the residue remaining after the lighter fractions of oils, such as gasoline, kerosene, and distillate oils have been removed from the crude oil. The major source of data for the combustion of fuel oil is EPA AP-42. As described in detail for the coal combustion, various technologies of fuel combustion have been averaged, according to their relative weight on the market.

### *7.2.1.5 Electricity from Natural Gas*

Raw natural gas is a mixture of HC, $N_2$, $CO_2$, sulfur compounds, and water. It may have any range of compounds from mostly $CH_4$ to inert gases, such as nitrogen, $CO_2$, and helium, and smaller amounts of ethane, propane, and butane. Natural gas may be mined onshore, offshore, and in conjunction with petroleum processes. The average gross heating value is assumed to be approximately 8,900 kcal/scf (AP-42 1995).

### *7.2.1.6 Natural Gas Production*

#### *7.2.1.6.1 Mining and Cleaning Natural Gas*

The energy used to produce natural gas is provided by EIA *Natural Gas Annual*[85] and U.S. Bureau of Census[86]. The process energy is apportioned out by Delucchi (1993) among petroleum, natural gas, and natural gas liquids based on the following assumptions:

- Almost all the natural gas consumed, according to the Census Bureau, is used in field operations—natural gas lifting and reinjecting. These data correspond with data provided by EIA.
- Any energy used to reinject natural gas into wells is excluded from the natural gas precombustion processes, because reinjection is mainly used in oil wells; and the amount of electricity used for field equipment and processing plants is little relative to the amount of gas they produce.

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[81] From American Power Plant Data 1996. Power plant information is confidential data collected by Ecobalance.

[82] From American Power Plant Data 1996.

[83] From American Power Plant Data 1996.

[84] At an average of 4 L of diesel fuel to transport 28 metric tons per load to the coal ash monofill, from American Power Plant Data 1996.

[85] EIA 1990. *Natural Gas Annual 1989, Volume 1.*

[86] U.S. Department of Commerce 1990. *Census of Mineral Industries, Fuels, and Electrical Energy Consumed.*

Thus, energy in this model excludes gas reinjection energy requirements.

#### *7.2.1.6.2 Gas Sweetening*

The amine process, or gas sweetening removes and recovers hydrogen sulfide ($H_2S$). The recovered $H_2S$ gas is either (1) vented, (2) flared in waste gas flares or modern smokeless flares, (3) incinerated, or (4) used to produce elemental sulfur or sulfuric acid. Emissions from venting the gas into the environment are covered in the model. Vented gas is usually passed to a tail gas incinerator in which the $H_2S$ is oxidized to $SO_2$ and is then passed to the atmosphere out a stack. Emissions are mostly $SO_2$ due to the 100% conversion of $H_2S$ to $SO_2$. Very little particulate and NOx are emitted from this process. Emissions factors for the amine process come from AP-42 (1995).

#### *7.2.1.6.3 Transportation*

Natural gas is transported via high-pressure transmission lines. Compressors along these lines may be powered from various sources: gas-fueled reciprocating engines and gas turbines, and electric motors. Emissions are all different because of the various sources of power in the compressors: the turbines, the engines, and the electric motors, so all these sources are modeled in this study.

The total amount of gas consumed in the compressors is averaged over the various sources of power. However, most pipeline compressor units are reciprocating engines, as reciprocating engines are more efficient when they operate under a large load. And because many of the compressors operate under a large load, we assume that there are more reciprocating engines in the compressors than turbines (Delucchi 1993). To obtain a breakdown of energy sources for compressors in transmission pipelines, actual pipeline company data are used (Table 119).

**Table 119: Percent Horsepower for Pipeline Power in 1989[87]**

| | |
|---|---|
| Turbines | 24.2% |
| Engines | 73.4% |
| Electric | 2.5% |

Horsepower hours by type of compressor and the associated fuel combustion per horsepower-hour are used to obtain a weighted percent of energy and emissions caused by each type of compressor in transmission pipelines. Because electric power is so little relative to the other compressors (2.5%), it is averaged into the other two categories.

AP-42 (1995) provides emissions data for gas turbines and reciprocating engines. For both gas turbines and reciprocating engines, we used an average of emission factors for $NO_x$-controlled and $NO_x$ uncontrolled scenarios. These emissions factors include $NO_x$, CO, TOC, NMHC, $CH_4$, and PM10.

### *7.2.1.7 Natural Gas Combustion*

Natural gas is combusted in gas boilers. Emissions from natural gas combustion are primarily from improper operating conditions, such as inefficient mixing of fuel and air in the boiler, or an insufficient amount of air, etc. Emissions vary by the type and size of combustor and operating conditions.

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[87] DeLucchi 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Vol. 2, Appendix G.

Emissions factors for gas boilers were obtained from EPA AP-42 (1995) for $NO_x$, CO, $SO_x$, PM, CO, and TOCs. $NO_x$ control technologies are required for many boilers to comply with strict $NO_x$ emissions standards, so it is assumed that most boilers have $NO_x$ control technologies. Therefore, emissions factors for $NO_x$ in AP-42 (1995) use the factors for boilers with $NO_x$ control technologies.

#### 7.2.1.8 Electricity from Nuclear Energy

Uranium contains two various isotopes—238U and 235U. 235U is used as a fuel for nuclear reactors because it is fissionable, so the atoms can be split, releasing large amounts of heat. However, natural uranium consists of more than 99% 238U and less than 1% 235U. To be used as a fuel, its 235U content must be enriched to 3%-5%.

The data included in the model are uranium hexafluoride (UF6) manufacturing, enrichment of 235U, and fuel rods manufacturing[88]. No data on waste disposal, plant construction, or emissions of radionucleides are included in the nuclear electricity production model.

#### 7.2.1.9 Electricity from Hydroelectric Power

Hydroelectric power generation refers to water used to generate electricity at plants in which turbine generators are driven by falling water. The hydroelectric power production model includes greenhouse gas emissions ($CO_2$ and $CH_4$) from operating a hydroelectric plant (flooded biomass decomposition). We have not included emissions from capital equipment and facilities construction in order to be consistent with the system boundaries discussed for petroleum diesel and biodiesel. There is some research that suggests that the life cycle flows from equipment and facilities construction are not negligible[89]. FERC[90] provides U.S. hydroelectric plant information such as average annual generation, plant capacity, and reservoir area and depth.

Explosives are excluded from the hydroelectric plant model, which encompass less than 5% of total energy consumed (Chamberlain et al). The data obtained on greenhouse gases emissions do not distinguish flooded biomass decomposition from new biomass decomposition and are assumed to refer only to flooded biomass.

#### 7.2.1.10 Electricity per Geographical Zone

Table 120 shows the electricity *production* percentages for the North American Electric Reliability Council (NERC) regions in the North America[91].

Some regions shown in Table 120 are split between Canada and the United States (WSCC for example); however, the electricity production percentages shown are only for the U.S. portion. The NERC regions are described in Figure 83.

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[88]Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL). Environmental Series No. 132. p A15. Berne, February 1991, and E.E. El-Hinnawi: Environmental Impacts of Production and Use of Energy. Tycooli International 1981.

[89] Chamberlain et al provide life cycle data on construction materials and energy (Chamberland, Andre, and Levesque, S. Hydroelectricity, an Option to Reduce Greenhouse Gas Emissions from Thermal Power Plants. *Energy Cons. Mgmt* Vol. 37, Nos. 6-8, pp. 885-890). Chamberland's life cycle study is based on a group of facilities in northern Canada whose average life span is 100 years and produces 62,200 GWh of electricity annually.

[90] FERC database 1996.

[91] Electricity source percentages from: EIA-759, U.S. Department of Energy, 1995 Electric Utility Net Generation by NERC Region and Fuel Type.

**Table 120: Share of Power Generation Source by Region in North America**

| | NERC Region | | | | |
|---|---|---|---|---|---|
| ***Fuel Type*** | ***NPCC*** | ***ECAR*** | ***WSCC*** | ***ERCOT*** | ***SERC*** |
| HFO | 10.7% | 0.3% | 0.1% | 0.1% | 3.4% |
| Hydro | 15.4% | 0.5% | 40.6% | 0.3% | 4.6% |
| NG | 18.3% | 0.5% | 10.2% | 37.4% | 5.9% |
| Nuclear | 35.1% | 10.4% | 12.8% | 17.1% | 29.5% |
| Coal | 20.5% | 88.3% | 36.3% | 45.2% | 56.6% |

| | NERC Region | | | | |
|---|---|---|---|---|---|
| ***Fuel Type*** | ***MAAC*** | ***MAPP*** | ***MAIN*** | ***SPP*** | ***U.S. Average*** |
| HFO | 3.1% | 0.5% | 0.5% | 0.3% | 2% |
| Hydro | 0.8% | 8.4% | 1.4% | 2.9% | 9.8% |
| NG | 5.3% | 0.9% | 1.7% | 28.3% | 10.2% |
| Nuclear | 40.8% | 15.9% | 42.4% | 15.7% | 23% |
| Coal | 50% | 74.3% | 54% | 52.8% | 55% |


**Figure 83. Map of the NERC regions in the United States and Canada**

### 7.2.2 Fertilizers and Agrochemicals

Nitrogen applied to soybeans is assumed to be in the form of ammonium nitrate ($NH_4NO_3$), which is produced by neutralizing nitric acid ($HNO_3$) with $NH_3$. The process involves several operations including solution formation and concentration, solids formation, finishing, screening, and coating, and product bagging.

The modeling of nitrogen fertilizer production is shown in Figure 84.

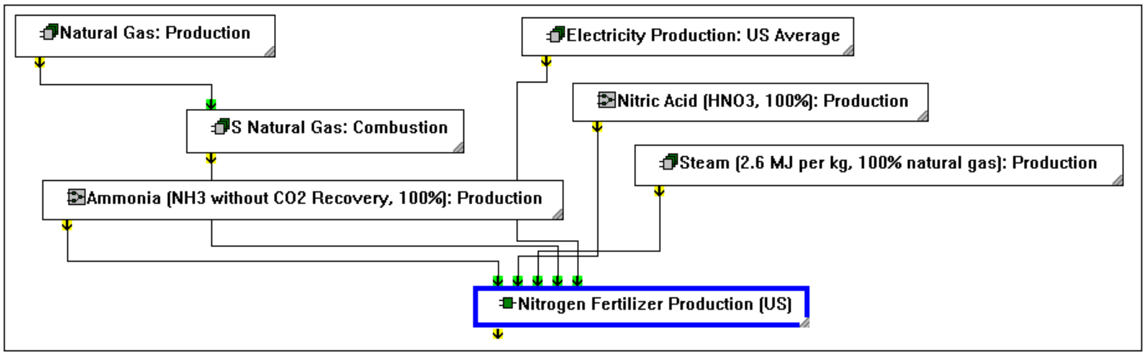


**Figure 84: Nitrogen Fertilizer Modeling**

As shown in Figure 84, inputs to the process include $HN0_3$, $NH_3$, and energy (electricity, natural gas, and steam). The amounts of $HN0_3$ and $NH_3$ used are based on the stoichiometry of the reaction and accounting for a 98% yield. The amount of energy used is based on contact with representatives from the Fertilizer Institute. Emissions released from the production of ammonium nitrate include particulate matter and ammonia (Air Chief, 1995).

Process flows associated with nitric acid and ammonia production are also taken into account. These are modeled based on Ecobalance's database DEAM$^{TM}$. The production of electricity, steam, and natural gas are also based on data from DEAM$^{TM}$.

Phosphorous applied is assumed to be in the form of TSP. In the granular process method used to produce TSP, ground phosphate rock or limestone is reacted with phosphoric acid in one or two reactors in series. Figure 85 describes the modeling of phosphorous fertilizer production.

The process requirements for TSP production are described in a survey done by the Fertilizer Institute on production costs. It lists a weighted average of inputs per ton of TSP produced. Thirteen phosphate fertilizer companies were surveyed for the report. The inputs required are phosphoric acid, phosphate rock, electricity, natural gas, and fuel oil. Emissions associated with TSP production include fluoride and particulate (Air Chief 1995).

Phosphoric acid is produced by reacting sulfuric acid ($H_2SO_4$) with naturally occurring phosphate rock. The phosphate rock is dried, crushed, and then continuously fed into the reactor along with $H_2SO_4$. The reaction also combines calcium from the phosphate rock with sulfate, forming calcium sulfate ($CaSO_4$), commonly referred to as gypsum. A weighted average of process inputs for 18 North American facilities is listed in the production cost survey produced by the Fertilizer Institute. It lists $H_2SO_4$[92], phosphate rock, and electricity as process inputs. Emissions include air emissions of fluoride and fluorine as well as possible leaching from cooling ponds (Air Chief 1995).

[92] Process flows associated with sulfuric acid will also be included in TSP production. Process inputs are listed by the Fertilizer Institute (1995) as a weighted average for 18 North American facilities. Emissions are based on EPA AP-42.

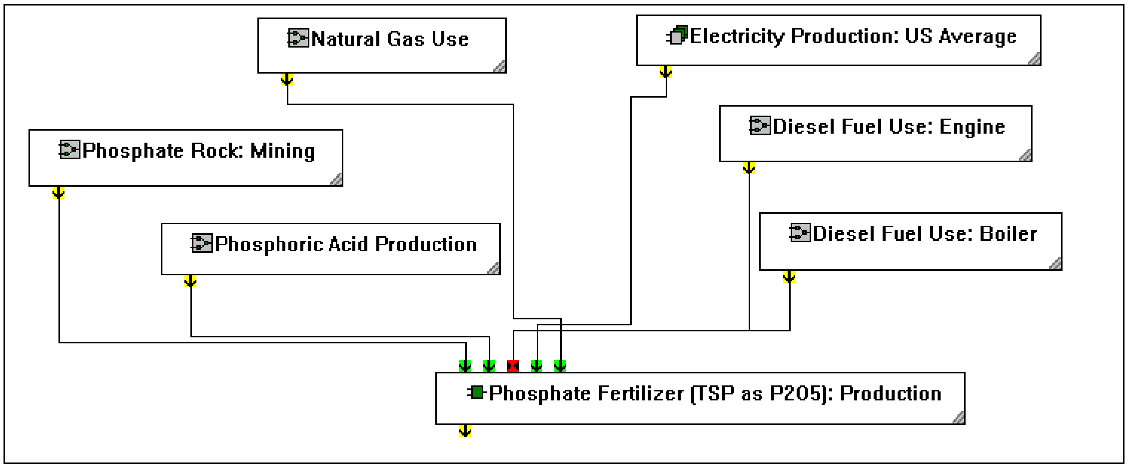


**Figure 85: Phosphorous Fertilizer Modeling**

Phosphate rock is mined primarily in Florida and North Carolina. Electricity use and overburden are given as weighted averages for 13 mines in the Fertilizer Institute's Production Cost Survey. Emissions include particulate and emissions from diesel mining equipment.

Potassium applied is assumed to be in the form of $K_2O$ (Phosphate and Potash Institute 1996). The modeling of potassium fertilizer production is shown in Figure 86.

Potassium fertilizer production involves the potash mining. The amount of energy used in the mining process is based on information in *The Fertilizer Handbook* (The Fertilizer Institute 1982). The values reported in *The Fertilizer Handbook* were based on a 1980 study. Therefore, the values have been reduced by 15% to account for energy efficiencies over time. Emissions released from the mining of potash include particulate matter (Air Chief 1995).

The modeling of agrochemical production is based on Ecobalance's database DEAM™, with aggregated data on the production of chemicals primarily taken from *Energy in World Agriculture* (Elsevier 1987). Energy consumed per kg of agrochemicals produced:

- Natural gas: 0.64 kg/kg
- Coke: 0.045 kg/kg
- Light fuel: 1.89 kg/kg
- Steam: 16.5 kg/kg
- Electricity: 24.4 MJ/kg.

Distances associated with transporting fertilizer and chemicals are assumed to be 500 miles by train and 50 miles by truck (Delucchi 1993). The energy associated with this transport is assumed to be included in the energy required to produce the fertilizer. Table 121 shows the energy required to produce the fertilizer and agrochemicals used in this study.

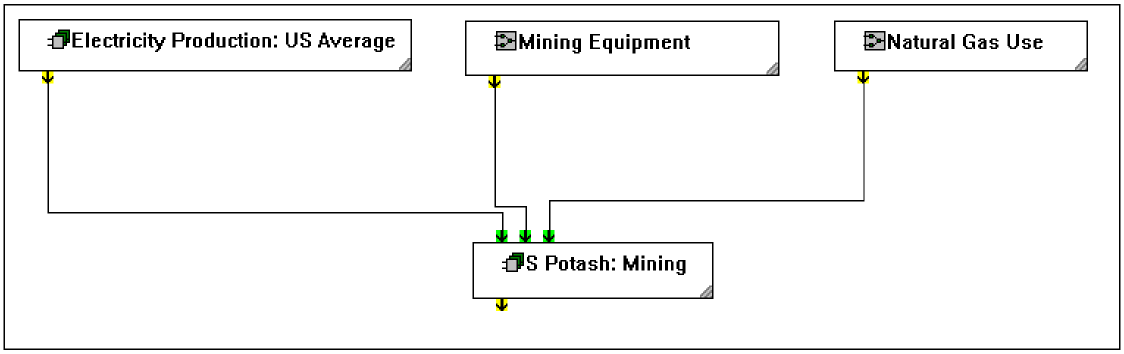


**Figure 86: Potassium Fertilizer Modeling**

**Table 121: Energy Content of Fertilizers and Agrochemicals**

| ***Material*** | ***Total Energy (MJ/kg)*** |
|---|---|
| Nitrogen Fertilizer ($NH_4NO_3$ as N) | 66.8 |
| Phosphorous Fertilizer (TSP as $P_2O_5$) | 12.8 |
| Potash Fertilizer ($K_2O$) | 4.6 |
| Agrochemicals | 263.7 |